PRELIMINARY PERMIT TO CONSTRUCT EVALUATION

COMPANY NAME AND ADDRESS:

La Jolla Energy Development Inc.
2882- C Walnut Ave.
Tustin, CA 92780
SCAQMD ID# 128069

EQUIPMENT DESCRIPTION:

Section H of the La Jolla Energy Facility Permit, ID# 128069

Equipment	ID No.	Connected To	Source Type/ Monitoring Unit	Emissions	Conditions
Process 1: INTERNAL COMBUSTION – TURBINES – POWER GENERATION					
TURBINE, GAS, UNIT NO. 1, COMBINED CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL LM2500 WITH STEAM OR WATER INJECTION, 287.5 MMBTU/HR, WITH A/N: 385826	D1	C4, C5	NOX: MAJOR SOURCE	NOX: 2.5 PPMV NATURAL GAS (4) [RULE 2005]; NOX 89.5 PPMV (8) [40CFR 60 SUBPART GG]; NOX: 101.15 LBS/MMSCF (1) [RULE 2012]; CO: 6 PPMV (4) [RULE 1303 BACT]; CO: 2000 PPMV (5) [RULE 407]; VOC: 2 PPMV (4) [RULE 1303-BACT]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; SOX: 150 PPMV (8) [40CFR 60 SUBPART GG	12-1, 12-2, 29-1, 29-2, 40-1, 57-1, 63-1, 67-1, 73-1, 82-1, 82-2, 99-1, 99-2, 99-3, 195-1, 195-2, 296-1, 327-1
GENERATOR, 25 MW (A/N 385826)	(B2)				
GENERATOR, HEAT RECOVERY STEAM, DELTAK	(B3)				

(A/N 385826)					
CO OXIDATION CATALYST, ENGELHARD, WITH 66 CUBIC FEET OF TOTAL CATALYST VOLUME A/N 386200	C4	D1			12-3, 12-4, 12-5, 179-1, 179-2, 195-3
SELECTIVE CATALYTIC REDUCTION NO. 1, ENGELHARD, WITH 354 CUBIC FEET OF TOTAL CATALYST VOLUME WITH A/N 386200 AMMONIA INJECTION GRID (A/N 374455)	C5 (B6)	D1		NH3: 5 PPMV (4) [RULE 1303-BACT]	
STACK, TURBINE NO. 1 A/N: 385826	S7				
TURBINE, GAS, UNIT NO. 2, COMBINED CYCLE, NATURAL GAS, GENERAL ELECTRIC, MODEL LM2500 WITH STEAM OR WATER INJECTION, 287.5 MMBTU/HR, WITH A/N: 386205 GENERATOR, 25 MW (A/N 386205) GENERATOR, HEAT RECOVERY STEAM, DELTAK (A/N 386205)	D8 (B9) (B10)	C11, C12	NOX: MAJOR SOURCE	NOX: 2.5 PPMV NATURAL GAS (4) [RULE 2005]; NOX 89.5 PPMV (8) [40CFR 60 SUBPART GG]; NOX: 101.15 LBS/MMSCF (1) [RULE 2012; CO: 6 PPMV (4) [RULE 1303 BACT]; CO: 2000 PPMV (5) [RULE 407]; VOC: 2 PPMV (4) [RULE 1303-BACT]; PM: 0.1 GR/SCF (5) [RULE 409]; PM: 11 LBS/HR (5) [RULE 475]; PM: 0.01 GR/SCF (5A) [RULE 475]; SOX: 150 PPMV (8) [40CFR 60 SUBPART GG	12-1, 12-2, 29-1, 29-2, 40-1, 57-1, 63-1, 67-1, 73-1, 82-1, 82-2, 99-1, 99-2, 99-3, 195-1, 195-2, 296-1, 327-1
CO OXIDATION CATALYST, ENGELHARD, WITH 66 CUBIC FEET OF TOTAL CATALYST VOLUME A/N 386202	C11	D8			

SELECTIVE CATALYTIC REDUCTION NO. 2, ENGELHARD, WITH 354 CUBIC FEET OF TOTAL CATALYST VOLUME WITH A/N 386202 AMMONIA INJECTION GRID (A/N 386202)	C12 (B13)	D8		NH3: 5 PPMV (4) [RULE 1303-BACT]	12-3, 12-4, 12-5, 179-1, 179-2, 195-3
STACK, TURBINE NO. 2 A/N: 386205	D14				
Process 2: AMMONIA STORAGE					
STORAGE TANK NO.1, WITH A VAPOR RETURN LINE, AQUEOUS AMMONIA, 19% SOLUTION, 5,000 GALLONS A/N: 386204	D15				57-1, 71-1, 157-1

EQUIPMENT LOCATION:

5640 S Fairfax Ave
Los Angeles, CA 90056

Facility Ownership
The applicant for this project is La Jolla Energy Development Inc. Based on information provided by La Jolla Energy and its attorney in the letter addressed to Hamilton Stoddard dated May 30, 2001, and a letter to Barbara Baird dated June 15, 2001, La Jolla Energy Development and Stocker Resources plan to enter into a joint partnership known as Baldwin Energy Facility No. 1 to run the power plant. Information provided in a telephone conversation with Steve Wilburn, president of La Jolla Energy on June 19, 2001 indicates that the partnership has not been formed yet and current ownership of the plant is with La Jolla Energy. However, EPA considers projects which are co-located to be under common control, and therefore, for purposes of this analysis, the project will be considered a joint venture between Stocker Resources and La Jolla Energy Development.

One of the aspects of the ownership issue is the offset requirements, which are described in further detail under the Emissions section of this report.

COMPLIANCE RECORD REVIEW

The following Stocker Resources ID's were checked for recent compliance activity in the AQMD database: 83753, 83754, 83756, 83757 (all at 5640 Fairfax Ave), 83888, 83889, 84344, and 112164 (at various addresses). Stocker's facility is a NOx RECLAIM facility subject to annual inspections and audits. The District's compliance records indicates that the company has been issued 3 notices of violation (NOV) and 2 notices to comply (NC) within the past 5 years as summarized below:

Notice Type	Notice No.	Issue date	Rule	Description
NOV	P28264	8-15-2000	1173 (c)(1)	Fugitive Leaks
NC	C56856	4-18-2000	201	Permit to Construct
NC	C56053	9-2-1999	2012 (d)(2)(B)	RECLAIM Reporting
NOV	P21319	6-17-1998	2004(f)(1)	Fugitive Leaks
NOV	P18914	4-4-1996	2004 463	Fugitive Leaks

BACKGROUND:

Baldwin Energy is proposing the installation of two General Electric LM2500 gas turbines, rated at 25 MW each. The turbines will initially operate as simple cycle units with water injection only for NOx control. Expected controlled NOx exhaust concentrations during "Phase I" of the project are 20 ppm.

In March 2002, Baldwin will begin installation of a heat recovery steam generator (HRSG), an Selective Catalytic Reduction (SCR) system for NOx control, and an oxidation catalyst for CO (and some VOC) control. Steam generated in the HRSG will be injected into the combustor for NOx control, there will not be a steam turbine. Use of the steam injection and SCR catalyst will reduce NOx emission concentrations to 2.5 ppm.

Existing Site

The facility will be located on existing oil field property known as the Inglewood Oilfield, on which Stocker Resources operates an oil production facility under AQMD permits (ID# 83753). The project proponent, has requested to be assigned a separate AQMD ID# from the existing Stocker ID's at this site address. As previously discussed the facilities are considered to be under common control, and the emissions from both IDs (Stocker 83753 and La Jolla 128069) are considered additive for purposes of this evaluation.

The site location is in the Baldwin Hills area, at approximately 700 feet from the Kenneth Hahn State Recreation Area, and bordered by La Cienega Blvd. on the west. The Kenneth Hahn State Recreation Area is within the boundary of the Baldwin Hill Conservancy, created by SB 1625, Murray (2000). The Conservancy is in the process of turning the entire two-square mile area within the Conservancy's jurisdiction into the Baldwin Hills State Park.

There are no schools within 1000 feet of the facility. The nearest schools (K-12), ranging from a mile to 1½ miles from the site, are Windsor Magnet (5215 Overdale Dr.), Baldwin Hills Elementary (5241 Rodeo Dr.), Hillcrest Elementary (4041 Hillcrest Dr.), and Marlton School (4000 San Tomas Dr.).

La Jolla Energy, Inc. submitted an Application for Certification (AFC) with the California Energy Commission (CEC), the state agency responsible for the siting of all power plants over 50 MW in the state, on May 15, 2001. La Jolla has asked for the project to be considered under the 21-day expedited siting process for emergency peaking plants.

The facility has opted into the NOx Reclaim program, and the facility will also be subject to Title V because the facility NOx emissions under both the Interim and Permanent projects exceed the Title V thresholds.

The following applications were submitted for this project:

Table 1 – Project Application Numbers

A/N	Submittal Date	Equipment
385826	5/8/01	Turbine #1
386200	5/15/01	SCR #1
386202	5/15/01	SCR #2
386204	5/15/01	Ammonia Storage Tank
386205	5/15/01	Turbine #2
386224	5/15/01	Title V Revision

PROCESS DESCRIPTION:

New Turbines

Baldwin Energy Facility No. 1 is proposing the installation of 2 new combustion turbines located at the existing Stocker Resources oil production field in Baldwin Hills. The turbines will initially be operated as simple cycle with water injection, and later in Phase II of the project, will be converted to combined cycle units with steam injection and SCR for NOx control, and oxidation catalyst for CO control. The project is known as the Baldwin Energy Facility No. 1. The turbines will be reconditioned GE LM2500PEs, with a maximum output rating of 25 MW each. Each turbine will be fired on the well head gas produced on site. A summary of the fuel analyses is contained in Appendix D.

Net heat rate is approximately 11,499 btu/kWh (HHV) for simple cycle, and 8804 (HHV) for combined cycle. There will be one stack per turbine. Each stack is approximately 70 feet high.

CEMS Systems

Continuous emission monitoring in the turbine exhaust will be required for NOx, CO, and O2. Presently, the proposal is to install a Horiba model ENDA-E4220L CEMS to measure these parameters.

Other parameters which will be required to be measured and recorded include the fuel use (Rule 2012 and 40CFR), steam injection rate (Rule 2012 and 40CFR), ammonia injection rate (Rule 2012), exhaust temperature prior to the SCR catalyst (Rule 2012), turbine output (Rule 2012), and pressure drop across the SCR catalyst. Also, the AQMD requires that the ammonia slip be monitored (Rule 1303) either through comparison of NOx concentration prior to and after the SCR catalyst, or the applicant may propose a direct ammonia slip monitor. In either case, the monitor will be needed for precise control of the ammonia injection rate as well as determination of ammonia slip.

TABLE 2 - Gas Turbine Data

Specification	PHASE I	PHASE II
Manufacturer	GE	GE
Model	LM2500 PE	LM 2500 Steam Injected
Fuel Type	Well-head gas/Natural Gas, 1050 Btu/scf	Well-head gas/Natural Gas, 1050 Btu/scf
Maximum Fuel Consumption	0.2837 mmscf/hr	0.2293 mmscf/hr
Maximum GT exhaust flow	8.871 mmscf/hr	7.430 mmscf/hr
Gas Turbine Heat Input	287 mmbtu/hr maximum	241 mmbtu/hr maximum
Maximum Gas Turbine Output	25 MW	27.4 MW
Net Plant Heat Rate, LHV	10455 Btu/kw-hr	8003 Btu/kw-hr
Net Plant Heat Rate, HHV	11499 Btu/kw-hr	8804 Btu/kw-hr
Net Plant Efficiency (LHV)	33%	43%
Unabated NOx Emission Rate	179 ppm (natural gas)	179 ppm (natural gas)

Control Systems

The control systems will be installed in 2 phases. In Phase 1 of the project, the NOx emissions from the turbines will be controlled by a water injection system only. There will be no CO control. Phase I will begin in September 2001 and last until approximately March 2002 (estimated at 181 days from 9/6/01 to 3/5/02).

Phase I

Water injection begins when the turbine reaches a load of approximately 40%, or 10 MW. Water injection rates will vary depending on turbine load and ambient conditions, with the maximum injection rate being about 36 gpm. Fresh water will be supplied by California-American Water Company. The water will be deminerilized prior to use in the turbine.

Phase II

In Phase 2 of the project, an SCR system and a CO catalyst will be installed. Also, a heat recovery steam generator will be added, and the turbines exhaust gas will be used to generate steam. Steam from the HRSG will be used for injection into the combustor for NOx control in lieu of the water injection. The turbine will be shut down for several weeks during the installation of these systems, and re-start up is scheduled for the beginning of April 2002.

Full steam injection rate will be 71,000 lbs/hr at 850°F.

The SCR catalyst will be manufactured by Engelhard. The manufacturer guarantee for NOx control efficiency and catalyst life is 90% reduction to 2.5 ppm outlet NOx for 3 years or 26,280 hours. Pressure drop across the SCR catalyst is approximately 4”. Typical SO2 to SO3 conversion rates for SCR catalysts are about 4-6%. Optimum exhaust temperature range for SCR catalyst operation is 690°F to 720°F, with a maximum limit of 800°F.

It is anticipated that ammonia injection will begin approximately 20 minutes after initial start up.

Table 3 - SCR Data

Specification	
Manufacturer	Engelhard Corporation
Catalyst Type	NOxCAT VNX-HT vanadia-titania
Catalyst Volume	354 ft^3
Space Velocity	52,560 hr-1
Ammonia Injection Rate	57 lbs/hr max
Ammonia Slip	5 ppm 1 hour average at 15% O2
Outlet NOx	2.5 ppm 1 hour avg at 15% O2
SCR/CO Catalyst Cost	$819,000
Catalyst Replacement Cost	$238,000
Min/Max Operating Temp	690/800°F

CO catalyst
The CO catalyst is also manufactured by Engelhard. Emission guarantee is for 90% CO reduction to 4 ppm exhaust concentration for 3 years or 26,280 hours. The pressure drop across the CO catalyst is approximately 1-1.5”. Typical SO2 to SO3 conversion rates for CO catalysts are about 50-60%.

Table 4 - CO Catalyst Data

Specification	
Manufacturer	Engelhard Corporation
Catalyst Type	vanadia/titania
Catalyst Volume	66 ft^3
Space Velocity	280,080 hr-1
Outlet CO	4 ppm (1 hour avg) at 15% O2
Outlet VOC	1.4 ppm (1 hour average) at 15% O2
Minimum Operating Temp	690°F

<u>Cooling Towers</u>
The applicant has stated there will be no cooling towers.

<u>Ammonia Storage</u>
The proposed aqueous ammonia tank will be 5,000 gallons. There will be a 1 foot high spill containment area around the tank capable of handling 110% of the tank volume (approximately 5500 gallons, or 735 ft^2). Based on the expected use of ammonia shown below, there will be about 25 tank turnover per year, or about twice per month. During

loading, the displaced ammonia vapors will be controlled by venting the vapors back into the tank truck. Daily breathing losses will be controlled completely with the 25 psig pressure relief valve.

Expected maximum ammonia use is about 7.4 gallons per hour (57 lbs/hr / 7.7 lbs/gal) for each SCR, for a total of 15 gallons per hour maximum for the 2 SCRs. Approximate annual aqueous ammonia use is 127,500 gallons based on the 8500 hours per year operation estimate provided by the applicant.

EMISSIONS:

Emissions from the gas turbines are affected by several factors, most importantly, the mode of operation and ambient meteorological conditions, such as humidity, temperature, and pressure. The two basic operational modes from an emissions standpoint are start-up and baseload operation. Due to technical unavailability of emissions control, during start ups, emission concentrations will be higher. However, in some cases, due to lower fuel use and heat inputs during starts, actual mass emissions are lower than during the baseload operation.

In Phase 1, when the SCR has not been installed yet, the turbine NOx emissions will be controlled only by a water injection system which will begin operation approximately 5 minutes after turbine start up. In Phase 2, steam injection will begin after about 10 minutes of turbine operation, with full SCR and CO control after 20 minutes.

Phase I of this project is deficient in several categories specific to BACT/LAER. **Phase I of this project is deficient in several categories specific to BACT/LAER.** **As such, AQMD cannot issue permits to construct for the phase I project proposed by the applicant.**

The proposed Phase II project would meet all compliance requirements pending resolution of Rule 1303 and 2005 concerning the alternatives analysis, upon supplying the AQMD the proper amount of offset credits.

The proposed Phase II project would meet all compliance requirements pending resolution of Rule 1303 and 2005 CEQA issues and upon supplying the AQMD the proper amount of offset credits. Therefore, the following rule compliance, BACT, and offset requirements

For AQMD New Source Review emission offset and BACT purposes, maximum and average daily emissions on a per turbine basis need to be considered for those pollutants not subject to RECLAIM. RECLAIM NOx is evaluated for both turbines on an annual basis in determining the necessary RECLAIM Trading Credits (RTCs).

For those pollutants whose emission calculations are based on exhaust concentrations (NOx, ROG, CO, and NH3), the maximum exhaust rate was determined from EPA Method 19. Reference Appendix A. This was used as the maximum exhaust flow rate in the calculation of emissions during normal baseload operation. The applicant supplied estimated turbine loads during various stages of start up, and those load percentages were used in the calculations of emissions during start up.

For the remaining pollutants (PM10 and SOx) whose emissions are based on heat input based emission factors, maximum heat input rate was determined using the given heat rate (HHV), and the gross maximum output during each phase of the project. This was used as the maximum heat input in the calculation of emissions during normal baseload operation. The applicant supplied estimated turbine loads during various stages of start up, and those load percentages were used in the calculations of emissions during start up.

Reference Appendix A for the calculations. Following is a summary:

1. Maximum Turbine Emissions

Table 5 - Maximum Emissions Phase I

Pollutant	Maximum Emissions	
	Lbs/hr	lbs/day
NOx	21.89	517.08
CO	26.21	629.04
VOC	1.50	36.0
PM10	1.90	45.36
SOx	0.23	5.52

Note:
Maximum emissions include a daily start up for NOx. All other pollutants are based on 24 hrs/day maximum load operation.

Table 5 - Maximum Emissions Phase II

Pollutant	Maximum Emissions	
	lbs/hr	lbs/day
NOx	8.64	60.4
CO	8.42	59.0
VOC	0.69	10.8
PM10	1.83	43.9
SOx	0.086	1.83
NH3	1.67	39.52

Note:
Maximum emissions include a daily start up for all pollutants except PM10. PM10 daily emissions are based on 24 hrs/day maximum load operation.

2. 30 Day Average Emissions for Non-RECLAIM Pollutants Phase II Only

The 30 Day Average emissions estimates assumes the following operational scenario:

For CO, VOC, PM10, and SOx:
One month consists of 30 days, 720 hours
The turbines operate under 24 hours/day, 30 days/month start-up 1 hr/day and baseload 23 hr/day.

Table 6 - 30 Day Average Emissions and Required Offsets

Pollutant	Monthly Emissions	30 Day Average Emissions, 1 Turbine	Offset Factor	Required Offsets, 1 Turbine	Required Offsets, 2 Turbines
	Lbs/month	lbs/day		lbs/day	lbs/day
CO	1770	59	1.2	71	142
VOC	324	11	1.2	13	26
PM10	1308	44	1.2	53	106
SOx	54.9	2	N/A	< 4 tons/yr, exempt	< 4 tons/yr, exempt

3. RECLAIM Annual Average NOx Emissions

Annual average NOx emissions are estimated for the purposes of determining the required RTCs for the 1st year of operation pursuant to Rule 2005. The annual NOx estimation is based on the permanent project operation and assumes the following for each turbine:

Turbines operate 365 days, 24 hours/day, with 365 start ups (1 start per day), and the remaining hours of operation (8395) under maximum load.

The following table summarizes the calculations:

TABLE 7 – Annual Average NOx Emissions – 2 Turbines

Operating Scenario	Annual Operation(1)	Hourly Emission Rate	Cumulative Emissions(1)
	hrs/yr	lbs/hr	lbs/operation-yr
Phase II Start Ups	730	17.69	12,913.7
Phase II Baseloads	16,790	2.68	44,997.2
		Total lbs/year	57,911

Notes:

(1) Total 2 turbines

EVALUATION:

PART 1 SCAQMD REGULATIONS

RULE 212 – Standards for Approving Permits
The new gas turbines at are considered a significant project under this rule due to the fact that the emissions exceed the daily maximums specified in subdivision (d). Therefore, public notice is required to be sent to all addresses within a ¼ mile radius of the project, a local newspaper publication, as well as those parties listed in subdivision (g) of the rule, including EPA Region IX, CARB, chief executives of both the city and county of Los Angeles, any comprehensive regional land use planning agency, and affected State and Federal Land Managers.

The required public notice and comment period under this rule is 30 days.

Rule 218 – Continuous Emission Monitoring
Each of the turbines will be required to install a CO CEMS to verify emissions of CO meet the hourly and daily emission limits. The CO CEMS will need to comply with the requirements of Rule 218, and the facility will need to submit a CEMS application for AQMD review and approval prior to installing the CEMS.

RULE 401 – Visible Emissions
Visible emissions are not expected under normal operating conditions of the turbines.

RULE 402 – Nuisance
Nuisance problems are not expected under normal operating conditions of the turbines.

RULE 403 – Fugitive Dust
This rule requires use of best available control measures to minimize fugitive dust formation from "active operations" including but not limited to, earth moving, construction, and vehicular movement. The rule prohibits active operations from causing visible emissions that extend beyond the facility's fenceline. Stocker/LJEDI has stated that the construction activities are expected to occur over less than 50 acres, and are therefore not considered a medium or large project under this rule. Stocker/LJEDI has further stated that they plan to utilize one or more of the best available control measures during construction of the turbines. Compliance with Rule 403 is expected.

Additionally, the California Energy Commission has indicated that the project proponent will be required, prior to the commencement of construction, to prepare a Construction Fugitive Dust Mitigation Plan that will specifically identify fugitive dust mitigation measures that will be employed for the construction of the project and related facilities.

RULE 407 – Liquid and Gaseous Air Contaminants
This rule limits the CO emissions to 2000 ppm max, and the sulfur content of the exhaust to 500 ppm for equipment not subject to the emission concentration limits of 431.1. Since the turbines are subject to the limits of Rule 431.1, only the 2000 ppm limit of this rule applies. Applicant data shows expected CO emissions from uncontrolled operation, and operation with steam or water injection to be below 2000 ppm. Under Phase II of the project, the use of the CO catalyst will reduce CO concentrations to 4 ppm. Compliance is expected and will be verified through CEMS data.

RULE 409 – Combustion Contaminants
The rule limits PM emissions to 0.1 gr/scf at 12% CO_2. The equipment is expected to meet this limit at maximum firing loads based on the calculations shown below (permanent project data):

Estimated exhaust gas	7.430 mmscf/hr
Maximum PM emissions	1.83 lbs/hr
Estimated CO_2% in exhaust gas	3%

Grain Loading = 1.83 lbs/hr (7000 gr/lb)

-------------------------- X 12/3
7.430 E+06 scf/hr

= 0.007 gr/scf

Compliance will be verified through the initial performance test.

RULE 431.1 – Sulfur Content of Natural Gas
Gas will be supplied through either Southern California Gas pipelines or Stocker Resources gas plant. Both types of gas are expected to meet the requirements of this rule. See Appendix D for sulfur analysis.

RULE 475 –Electric Power Generating Equipment
This rule applies to power generating equipment greater than 10 MW installed after May 7, 1976. Requirements are that the equipment meet a limit for combustion contaminants (combustion contaminants are defined as particulate matter in AQMD Regulation I) of 11 lbs/hr or 0.01 gr/scf. Compliance is achieved if either the mass limit or the concentration limit is met. Mass PM10 emissions from the turbines are estimated at 1.83 lbs/hr, and 0.007 gr/scf (see calculations under Rule 409 discussion). Therefore, compliance is expected. Compliance will be verified through the initial performance test.

REGULATION XIII – New Source Review

The project is subject to the offsets, modeling, and BACT requirements of New Source Review. Following is a discussion of each requirement.

1. Offsets

Stocker Resources ID# 87533 is over the offset threshold for VOC and CO. The existing facility PM10 balance is 2.14 tpy, and the new turbines will exceed add 16.06 tpy PM10. Current balance for SOx is 0 tpy, and the new turbines will add less than 1 tpy. Therefore SOx offsets are not required.

Offsets for VOC, PM10, and CO are based on a calendar monthly average in accordance with Rule 1306(b). Required offsets are shown in Table 6 above. Offsets will be required prior to issuing the permit, however Stocker/LJEDI has not yet provided the offsets for this project. Potential offset sources for this project are purchased ERCs, the State ERC Bank, and the AQMD's priority reserve as outlined in Rule 1309.1.

2. Modeling

Modeling is required for CO and PM10 emissions per Rule 1303(b). The latest version of Rule 1303, requires that through modeling, the applicant must substantiate that the project does not exceed the most stringent ambient air quality standard or a significant change in air quality concentration depending on the compliance status of each pollutant in the area. For pollutants which are considered in attainment, modeling must demonstrate the project plus the background will not exceed the state standard. For non-attainment pollutants, the modeling must show compliance with significant change in air quality concentration. The project location is in attainment for NO2 and CO, but non-attainment for PM10 and ozone.

Maximum project impacts of CO and PM10 emissions were determined using the ISCST model, version 00101 and the West LA meteorological data. The model was run for both the interim project and the permanent project. Tables 9 and 10 below shows the results from modeling analysis.

TABLE 9 - New Source Review Modeling Phase I Project

Pollutant	**Averaging Period**	**Increment ($\mu g/m^3$)**	**Background ($\mu g/m^3$)**	**Total Conc. ($\mu g/m^3$)**	**Exceed CAAQS?**
CO	1-hour	28.1	8050	8078	No
	8-hour	19.0	5175	5194	No
SO_2	1-hour	0.4	445.4	445.8	No
	24-hour	0.2	52.4	52.6	No
	Annual	0.04	10.5	10.5	No
PM_{10}	24-hour	0.7	74	74.7	Yes*
	Annual geometric mean	0.2	33.4	33.6	Yes*

TABLE 10 - New Source Review Modeling Phase II Project

Pollutant	Averaging Period	Increment ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Conc. ($\mu g/m^3$)	Exceed CAAQS?
CO	1-hour	23.3	8050	8073	No
	8-hour	5.6	5175	5181	No
SO_2	1-hour	0.4	445.4	445.8	No
	24-hour	0.2	52.4	52.6	No
	Annual	0.04	10.5	10.5	No
PM_{10}	24-hour	1.8	74	75.8	Yes*
	Annual geometric mean	0.4	33.4	33.8	Yes*

* Project increments are within the PM_{10} significance thresholds of 2.5 $\mu g/m^3$ (24-hr) and 1 $\mu g/m^3$ (annual).

The model was reviewed by AQMD modeling staff and deemed in compliance with Rule 1303 (refer to memo from Henry Hogo to Pang Mueller dated 6/8/01, included in Appendix F of this evaluation).

3. BACT

BACT is defined in AQMD Rule 1301 as follows:

BACT means the most stringent emission limitation or control technique which:

(1) has been achieved in practice for such category or class of source; or
(2) is contained in any State Implementation Plan (SIP) approved by the US EPA for such category or class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed source demonstrates to the satisfaction of the Executive Officer or designee that such limitations or control technique is not presently achievable; or
(3) is any other emission limitation or control technique, found by the Executive Officer or designee to be technologically feasible for such class or category of sources or for a specific source, and cost effective as compared to measures as listed in the Air Quality Management Plan (AQMP) or rules adopted by the District Governing Board.

This definition of BACT is consistent with the federal LAER definition.

The California Air Resource Board published a document entitled Guidance for Power Plant Citing and Best Available Control Technology, dated September 1999. In it, they summarize required BACT for combined cycle power plants as follows:

TABLE 11 – Required BACT

NOx	CO	VOC	PM10	SOx
2.5 ppmvd @ 15% O2, 1 hour rolling average	6 ppmvd @ 15% O2, 1 hour rolling average	2 ppmvd @ 15% O2, 1 hour rolling average OR 0.0027 lbs/MMbtu, HHV	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O2)

Source: CARB, Guidance for Power Plant Citing and Best Available Control Technology, dated September 1999.

The following emission levels are proposed for this project. Note that these levels generally represent guaranteed emissions under baseload operating conditions.

TABLE 12 – Phase I Proposed Emission Levels

NOx	CO	VOC	PM10	SOx
20 ppmvd @ 15% O2, 1 hour rolling average	40 ppmvd @ 15% O2, 1 hour rolling average	4 ppmvd @ 15% O2, 1 hour rolling average	Exclusive use of process gas fuel with sulfur content less than 16 ppm.*	Exclusive use of process gas fuel with sulfur content less than 16 ppm.*

TABLE 13 – Phase II Proposed Emission Levels

NOx	CO	VOC	PM10	SOx
2.5 ppmvd @ 15% O2, 1 hour rolling average	4 ppmvd @ 15% O2, 1 hour rolling average	1.4 ppmvd @ 15% O2, 1 hour rolling average	Exclusive use of process gas fuel with sulfur content less than 16 ppm.*	Exclusive use of process gas fuel with sulfur content less than 16 ppm.*

* Expected sulfur content levels based on review of gas analyzes.

The proposed Phase I control levels will not meet BACT levels established for CO and VOC for the project. Phase II emission levels and proposed controls will meet the BACT requirements for all criteria pollutants. See discussion under Rule 2005 for more detailed analysis of BACT for NOx.

Ammonia Emissions

After installation of the SCR during Phase II of the project, the turbines will emit ammonia. Rule 1303(a)(1) requires the use of BACT for ammonia emissions. The 1999 CARB BACT guidance recommends ammonia BACT levels for large gas turbines set at not more than 5 ppm. The project will meet the required 5 ppm ammonia slip limit based on the manufacturer guarantee from Engelhard. Permit conditions will require measurement of the ammonia injection rate and calculation of ammonia slip with either use of NOx analyzers before and after the SCR, or an "ammonia slip" monitor. Reference condition 195.

RULE 1401 – Carcinogenic Air Contaminants

AQMD modeling staff ran a Tier 4 modeling analysis using the dispersion model ISCST (version 00101), and the risk assessment model ACE2588 using AP-42 toxic emission factors. The factors are summarized in Appendix E.

The modeling shows that the residential MICR is 0.91 in a million, and the on-site worker risk is 0.16 in a million. Both levels are below the Rule 1401 threshold limits of 1 in a million and 10 in a million. Calculated Acute Hazard Index using Ventura County factors was 0.0299, less than the rule limit of 1.0. Additionally, the Chronic Hazard Index (using AP-42 factors) was 0.0152 also less than the rule limit of 1.0.

The model was reviewed by AQMD modeling staff and deemed acceptable (see memo from Henry Hogo dated 6/8/01). Below is a summary of results.

TABLE 14 – Results of Health Risk Assessment

MICR ($X10^{-6}$)	Acute Hazard Index	Chronic Hazard Index
0.91	0.0299	0.0152

<u>Rule 1402 – Control of Toxic Air Contaminants from Existing Sources</u>
This rule applies to existing sources, and is not a preconstruction review rule. However, for informational purposes, it is noted here that an HRA was performed for the existing Stocker Resources facility (ID# 87533) in 1997. The results of that analysis showed that the cancer risk from emissions generated on site were approximately 2.65 in a million, which is less than the action risk level (25 in a million) or significant risk levels (100 in a million) of the rule. Therefore, no further risk reduction measures were required. Additionally, since the HRA was conducted, the facility has electrified several IC engines, further reducing toxic emission levels.

<u>REGULATION XVII – Prevention of Significant Deterioration</u>
The South Coast Basin where the project is to be located is in attainment for NO2 and SO2 emissions. Therefore a PSD analysis for these pollutants must be conducted.

Rule 1701 sets forth the applicability requirements of this regulation, and states that the following sources are subject to PSD:

- Any new source or modification to an existing source where the emission increase is 100 or 250 tpy (depending on source category), or
- Any significant emissions increase at an existing major stationary source, or
- Any net emission increase at a major stationary source located within 10 km of a Class I area.

Rule 1702 (m)(1) lists the source categories subject to PSD. Any facility falling into the listed source categories which has emission of 100 tons per year or more of any contaminant regulated by the Act is considered a major stationary source.

One of the listed categories in paragraph (m)(1) is fossil fuel-fired steam electric plants with input of more than 250 mmbtu/hr. Since the Baldwin Energy turbines are fired on natural gas, rated above 250 mmbtu/hr, and will generate steam after installation of the HRSG, they could be considered to fall under this category. However, estimated NOx from the plant are less than 100 tons per year. Therefore, installation of the new turbines is not considered a major stationary source under Rule 1702(m)(2).

The existing Stocker Resources oil production field reported NOx emissions of approximately 45 tons/yr for the 1999-2000 year under the AQMD's RECLAIM program. Therefore, based on actual emissions, the existing site is not considered a major source under this regulation. Emissions have been reduced since then due to the electrification of IC engines. Annual NOx for the existing oil production site is now less than 10 tons.

The site is not located with 10 km of a Class I area (Class I areas in the South Coast District include Cucamonga, San Gabriel, San Gorgonio, San Jacinto, Agua Tibia Wilderness Areas, and Joshua Tree National Park). Rule 1702(f) states that in addition to these area, any other area defined in Part C of the Clean Air Act is also considered a Class I area. Part C of the CAA lists the following areas as Class I:

- international parks
- national wilderness areas which exceed 5,000 acres
- national memorial parks which exceed 5,000 acres
- national parks which exceed 6,000 acres

Kenneth Hahn State Recreation Area adjacent to the proposed site therefore does not meet the definition of a Class I area.

Furthermore, an unlisted source is subject to PSD if it emits 250 tpy of regulated contaminants [(m)(2)]. Paragraph (m)(3) states that a physical change to a stationary source not otherwise qualifying under paragraphs (m)(1) and (m)(2), would be considered a major source if the modification exceeds 100 tons per year.

Therefore, an analysis under PSD is not required for the proposed turbines.

Rule 1701, paragraph (b)(1) does however state that BACT must be utilized for any net emission increase at any stationary source. Since there is a net emission increase in both NOx and SOx, BACT for these pollutants is required under this regulation (as well as under Regulation XIII).

NOx BACT for this source has been determined to be an emission rate of 2.5 ppm over a 1 hour average. Stocker/LJEDI is proposing an initial project operation which does not meet BACT. Stocker/LJEDI's phase II is expected to meet BACT.

SOx for this source is exclusive use of natural gas with sulfur content of 1 grain/scf. The process gas to burned in the turbines is expected to meet this limit based on a review of the gas analysis.

Rule 2005 – NSR for Reclaim

Rule 2005 applies to the NOx emissions from the turbines. The rule requires new sources to provide RTCs, perform a modeling analysis, and provide BACT. Each of these requirements is discussed in further detail below.

1. RTCs

Rule 2005(b)(2)(A) requires that a new facility provide sufficient RTCs to offset emissions prior to the first year of operation on a 1-to-1 basis. Furthermore, paragraph (b)(2)(B) states that the RTCs must comply with the zone requirements of Rule 2005(e). The Stocker/LJEDI turbines are expected to begin operation on September 6, 2001, and since the facility is located in Zone 1, RTCs may only be obtained from Zone 1. The total required RTCS are shown in Table 7. Stocker/LJEDI is requesting use of the State ERC Bank to provide NOx offsets for years 2001, 2002, and 2003. A complete offset package has not been submitted yet.

2. Modeling

Modeling is required for NOx emissions per Rule 2005(c)(1)(B). For pollutants which are considered in attainment, modeling must demonstrate the project plus the background will not exceed the state standard. For non-attainment pollutants, the modeling must show compliance with significant change in air quality concentration. The project location is in attainment for NO2 and CO, but non-attainment for PM10 and ozone.

Maximum project impacts of NO2 were determined using the ISCST model, version 00101 and the West LA meteorological data. The model was run for both the interim and permanent projects. Tables 15 and 16 below show the results from modeling analysis.

TABLE 15 - NOx Modeling Results Interim Project

Pollutant	Averaging Period	Increment ($\mu g/m^3$)	Background ($\mu g/m^3$)*	Total Conc. ($\mu g/m^3$)	Exceed CAAQS?**
NO_2	1-hour	27.9	300.8	328.7	No
	Annual	1.2	54.7	55.9	No

TABLE 16 - NOx Modeling Results Permanent Project

Pollutant	**Averaging Period**	**Increment ($\mu g/m^3$)**	**Background ($\mu g/m^3$)***	**Total Conc. ($\mu g/m^3$)**	**Exceed CAAQS?****
NO_2	1-hour	23.9	300.8	324.7	No
	Annual	0.3	54.7	55.0	No

Modeling analysis for plume visibility is not required by Rule 2005 (or Rule 1303) because none of the Class I areas are within the prescribed distance.

3. BACT

The turbines will not meet BACT for the Phase I proposal. The only proposed NOx control for Phase I is a water injection system. The facility expects to receive an SCR and CO catalyst from Engelhard in March of 2002. After the installation of the SCR and CO catalysts in Phase II, the turbines should meet the required BACT levels. At that time, the turbine emissions will meet a 2.5 ppm NOx level on a 1 hour basis, this level is deemed to meet the BACT requirements for this project.

4. Additional Requirements for Major Sources

Rules 2005 and 1303 require that a major polluting facility (defined as a source emitting more than 10 tpy of NOx or VOC, 70 tpy of SOx or PM10,or 100 tpy of CO) also comply with the following:

1. Certify that all major sources in the state under control of the applicant are in compliance with all applicable federal emissions standards.

2. Submit an analysis of alternative sites, sizes, production processes, and environmental control techniques for the proposed source.

3. Conduct a visibility analysis if NOx emissions are over 40 tpy and the location of the source relative to a Class I area is within the distances specified in Table 4-1 of the rule.

The applicant 1) has certified on the 400-A form that all major sources under their control in the state comply with federal regulations, 2) has not done an alternative analysis, and 3) is not within the specified distances of a Class I area. Therefore, requirements 1 and 2 have been satisfied, but requirement 2 has not. Under Rules 2005 and 1303, an alternative analysis is normally not required where the project is exempt pursuant to CEQA as compliance with CEQA is considered equivalent. However, this project is exempt pursuant to an emergency exemption which may not assure there are no significant environmental effects. Therefore, the District is consulting with EPA to determine if the CEQA exemption is still deemed equivalent under these circumstances.

Rule 2012 – Monitoring Recording and Record Keeping for RECLAIM NOx

The new turbines will be classified as major sources for RECLAIM purposes. As such each turbine will be required to have a NOx CEMS and a fuel meter, and emissions must be reported through an RTU on a daily basis. The facility has up to 12 months from the date of installation of the turbines to install and have the required monitor systems certified. The facility must submit a CEMS application and plan for AQMD review and approval prior to receiving final certification on the CEMS.

Regulation XXX – Title V

Currently the existing Stocker Resources facility (ID# 87533) is excluded from Title V because emissions have been reduced below 10 tons/yr with the removal of the old IC engines. However, with the addition of the turbines, the Title V thresholds will be exceeded, and the facility will now be included in Title V.

As a Title V facility, public notification of this project is required. This is a 30 day public notice period. EPA is also afforded the opportunity to review and comment on the project within a 45 day review period. The Title V public notice will be combined with the Rules 212 notice, which is also required for this project.

PART 2 STATE REGULATIONS

California Environmental Quality Act (CEQA)

An CEQA analysis has not been prepared for this project. Normally, the CEC will conduct a review under their AFC process, which is equivalent to CEQA. However, since this project is being proposed under the Governor Davis' emergency power plant Executive Order, the project has been declared exempt from CEQA pursuant to the statutory exemption for emergencies.

PART 3 FEDERAL REGULATIONS

40CFR Part 60 Subpart GG – NSPS for Gas Turbines

NSPS applies to the turbines since the heat input is greater that 10.7 gigajoules per hour at peak load. Actual unit rating is $287(10^6)$ btu/hr X 1055 joules/btu = 302 gigajoules/hr.

The standards which will be applied to the turbine are as follows (see Appendix C for the calculations):

NOx = 89.5 ppm natural gas firing
SOx = 150 ppm

It is expected that the turbines will meet the NOx exhaust concentration BACT limit of 2.5 ppm with installation of the SCRs. Also, use of the process gas, which has sulfur content generally below 5 ppm, should allow compliance with the 150 ppm SOx exhaust concentration limit. Therefore, compliance with NSPS emission limits is expected. Additional requirement of subpart GG are the measurement of water or steam injection rate, fuel consumption, NOx, SOx, and O2 emissions (continuous monitoring by Method 20), as well as a performance test within 60 days of installation. Additionally, compliance with the NSPS monitoring requirements is expected.

<u>40CFR Part 63 – NESHAPS</u>
EPA is in the process of establishing a NESHAPS for gas turbines, a draft rule is expected in November 2000, with promulgation in 2002. Until the NESHAPs is promulgated, turbine MACT standards must be evaluated on a case-by-case basis. In this case, the single largest HAP emitted from the turbines is formaldehyde, at about 1.5 tpy combined from the 2 turbines. The total combined HAPs from the 2 turbines are about 2 tpy. Therefore, the turbines are below the major source thresholds of 10 tpy for a single HAP or 25 tpy for a combination of HAPs, and the turbines are not considered major sources of HAP, but would be considered area sources. The turbines will have an oxidation catalyst, which has been shown to reduce HAP emissions, and will most likely be the basis for the MACT standard.

<u>40CFR Part 64 - Compliance Assurance Monitoring</u>
This regulation applies to major stationary sources which use control equipment to achieve a specified emission limit. The rule is intended to provide “reasonable assurance” that the control systems are operating properly to maintain compliance with the emission limits. However, the CAM regulation only applies to facilities which operate emission control devices in accordance with federally enforceable regulations issued prior to 1990. Since the 1990 CAA Amendments, EPA incorporated “directly enforceable monitoring” into all emission regulations. Therefore the rule does not apply to facilities that are subject to EPA regulations issued after 1990.

The turbines are major sources for NOx and CO emissions, and will be subject to a BACT limit for each of these pollutants, as well as NSPS Subpart GG. The facility will provide monitoring as required under RECLAIM and NSPS for NOx and SOx.

40CFR Part 72 – Acid Rain Program

The acid rain program is similar to RECLAIM in that facilities are required to cover SO2 emissions with "SO2 Allowances" (similar to RTCs), or purchases of SO2 on the open market. The plant is also required to monitor SO2 emissions through use of fuel gas meters and gas constituent analysis (use of emission factors is also acceptable in certain cases) or with the use of exhaust gas CEMS. It is expected that the STOCKER/LJEDI facility will comply with the monitoring requirements of the acid rain provisions with the use of gas meters in conjunction with gas analysis.

Public Notice Requirements

The project is subject to public notice under Rule 212 and Rule 3006. Following are the notice requirements for each rule:

Rule 212

The project is subject to the noticing requirements of paragraph (g). This paragraph requires that notification follow the procedures of 40 CFR51, Section 51.161(b), and 40 CFR124, section 124.10. Rule 212(g) also requires 1) the AQMD analysis and information submitted by the operator must be available for public inspection in an area near the source, 2) notice by prominent advertisement in the affected area, and 3) mailing a copy of the notice to EPA, CARB, chief executives of the city and county where the source is located, any land use agencies, State and Federal Land Managers or Indian Governing Body whose lands may be affected by the project.

In addition to the above, Section 124.10 requires that the notice be sent to Federal and State agencies with jurisdiction over fish, shellfish, and wildlife resources and over coastal zone management plans, the Advisory Council on Historic Preservation, State and Historic Preservation Officers.

The applicant must also distribute the notification to all addresses within a ¼ mile radius of the facility.

Rule 3006

In addition to the parties receiving the notice under Rules 212, Rule 3006 requires the notice be sent to those who request in writing to be on a list and other means determined by the EO to insure adequate notice to the affected public. Rule 3006 also requires that the notice contain the following:

i) The identity and location of the affected facility;
(ii) The name and mailing address of the facility's contact person;

(iii) The identity and address of the South Coast Air Quality Management District as the permitting authority processing the permit;
(iv) The activity or activities involved in the permit action;
(v) The emissions change involved in any permit revision;
(vi) The name, address, and telephone number of a person who interested persons may contact to review additional information including copies of the proposed permit, the application, all relevant supporting materials, including compliance documents as defined in paragraph (b)(5) of Rule 3000, and all other materials available to the Executive Officer that are relevant to the permit decision;
(vii) A brief description of the public comment procedures provided; and,
(viii) The time and place of any proposed permit hearing that may be held or a statement of the procedures to request a proposed permit hearing if one has not already been requested.

Title V also allows for a 45 day review and comment period by the EPA.

A copy of the notice and the mailing list of those sent the notice is included in this file.

CONCLUSIONS:

The following is a summary of applicable rules for each Phase:

Rule	Phase I	Phase II
212	Compliance Expected	Compliance Expected
218	Compliance Expected	Compliance Expected
401	Compliance Expected	Compliance Expected
402	Compliance Expected	Compliance Expected
403	Compliance Expected	Compliance Expected
407	Compliance Expected	Compliance Expected
409	Compliance Expected	Compliance Expected
431.1	Compliance Expected	Compliance Expected
474	Compliance Expected	Compliance Expected
Reg XIII Offsets	Pending	Pending
Reg XIII Modeling	Compliance Expected	Compliance Expected
Reg XIII BACT	Non-Compliance	Compliance Expected
1401	Compliance Expected	Compliance Expected
1402	Compliance Expected	Compliance Expected
Reg XVII	Non-Compliance BACT	Compliance Expected
2005 RTC	Pending	Pending
2005 Modeling	Compliance Expected	Compliance Expected
2005 BACT	Non-Compliance	Compliance Expected

2012	Compliance Expected	Compliance Expected
Reg XXX – Title V	Compliance Expected	Compliance Expected
CEQA	Compliance Expected	Compliance Expected
40CFR Part 60 Subpart GG	Compliance Expected	Compliance Expected
40CFR Part 63 Neshaps	Compliance Expected	Compliance Expected
40CFR Part 64 CAM	Compliance Expected	Compliance Expected
40CFR Part 72 Acid Rain	Compliance Expected	Compliance Expected
1303 2005 CEQA	Pending Resolution	Pending Resolution

Phase I of this project is deficient in several categories specific to BACT/LAER. As such, AQMD cannot issue permits to construct for the phase I project proposed by the applicant.

The proposed Phase II project would meet all compliance requirements pending resolution of Rule 1303 and 2005 issues concerning the alternatives analysis, and upon supplying the AQMD the proper amount of offset credits.

<u>CONDITIONS for Phase II operations only:</u>

<u>Turbine Conditions</u>

12-1 The operator shall install and maintain a measuring device to accurately indicate the fuel use of the turbine.
[Rule 2012, 40CFR60 Subpart GG]

12-2 The operator shall install and maintain a measuring device to accurately indicate the steam to fuel ratio of the turbine.
[Rule 2012, 40CFR60 Subpart GG]

29-1 The operator shall conduct source tests for the pollutants identified below:

Pollutants	Required Test Method	Averaging Time	Test Location
NOx	District Method 100.1	1 hour	Outlet
CO	District Method 100.1	1 hour	Outlet
SOx	District Method 6.1	1 hour	Outlet
ROG	Approved District Method	1 hour	Outlet
PM	Approved District Method	1 hour	Outlet
NH3	Approved District Method	1 hour	Outlet

The test shall be conducted within 60 days of the approval of the source test protocol, but no later than 180 days after initial start up of the turbines.

The test shall be conducted to determine the oxygen levels in the exhaust. In addition, the test shall measure the fuel flow rate (CFH), the flue gas flow rate, and the turbine generating output (MW).

The test shall be conducted in accordance with a District approved source test protocol. The protocol shall be submitted to the District engineer no later than 45 days before the proposed test date and shall be approved by the District before the test commences. The test protocol shall include the proposed operating conditions of the turbine during the test, the identity of the testing lab, a statement from the testing lab certifying that it meets the criteria of R304, and a description of all sampling and analytical procedures.

The test shall be conducted when this equipment is operating at loads of 100%, 75%, and 50% of maximum load.

The District shall be notified of the date and time of the test at least 10 days prior to the test.

[Rule 1303 – Offsets, Rule 1303 – BACT, Rule 2005]

29-2 The operator shall conduct source tests for the pollutants identified below:

Pollutants	Required Test Method	Averaging Time	Test Location
NH3	Approved District Method	1 hour	Outlet

The test shall be conducted at least quarterly during the first 12 months of operation of the SCR, and at least annually thereafter.

The test shall be conducted to determine the NH3 emissions at the outlet using District method 207.1 measured over a 60 minute averaging time period. The NOx concentration , as determined by the CEMS, shall be simultaneously recorded during the ammonia slip test. If the CEMS is inoperable, a test shall be conducted to determine the NOx emissions using District method 100.1.

The test shall be conducted to demonstrate compliance with the Rule 1303 concentration limit.

The test shall be conducted when the equipment is operating at 80 percent load or greater.

The test shall be conducted and the results submitted to the District within 45 days after the test date.

[Rule 1303 – BACT]

40-1 The operator shall provide to the District a source test report in accordance with the following specifications:

Source test results shall be submitted to the District no later than 60 days after the source test was conducted.

Emission data shall be expressed in terms of concentration (ppmv), corrected to 15 percent oxygen, dry basis.

All exhaust flow rate shall be expressed in terms of dry standard cubic feet per minute (DSCFM) and dry actual cubic feet per minute (DACFM).

All moisture concentration shall be expressed in terms of % corrected to 15%.

Emission data shall be expressed in terms of mass rate (lbs/hr). In addition, solid PM emissions, if required to be tested, shall also be reported in terms of grains per DSCF.

Emission data shall be expressed in terms of lbs/mmcf.

Source test results shall also include turbine fuel flow rate under which the test was conducted.

Source test results shall also include turbine and generator output under which the test was conducted.

[Rule 1303 – Offsets, Rule 1303 – BACT, Rule 2005]

57-1 The operator shall vent this equipment to the SCR and CO control catalysts whenever the turbines are in operation.

[Rule 2005]

63-1 The operator shall limit emissions from this equipment as follows:

Contaminant	Emissions Limit
CO	1770 LBS IN ANY 1 MONTH
VOC	324 LBS IN ANY 1 MONTH
PM10	1308 LBS IN ANY 1 MONTH

For the purposes of this condition, the operator shall calculate monthly emissions by using monthly fuel use data, and the following emission factors: VOC – 1.92 lbs/mmscf and PM10 – 7.98 lbs/mmscf. Compliance with the CO emission limit shall be verified through CEMS data. Prior to installation of the

CO monitor, and for periods when the monitor is down, the operator shall use a factor of 9.59 lbs/mmcf to determine CO emissions.
[Rule 1303 – Offsets]

73-1 The operator may, at his discretion, choose not to use ammonia injection when the inlet exhaust temperature to the SCR reactor is 690 Deg F or less, not to exceed 20 minutes during start ups.
[Rule 1303 – BACT, Rule 402]

82-1 The operator shall maintain a CEMS to measure the following parameters:

CO concentration in ppmv
Concentrations shall be corrected to 15 percent oxygen on a dry basis
The CEMS will convert the actual CO concentrations to mass emission rates (lbs/hr) and record the hourly emission rates on a continuous basis.
The CEMS shall be installed and operated in accordance with an approved AQMD Rule 218 CEMS plan application. The operator shall not install the CEMS prior to receiving initial approval from AQMD.
The CEMS shall be installed and operated to measure CO concentration over a 15 minute averaging time period.
[Rule 1303 – BACT, Rule 218]

82-2 The operator shall install and maintain a CEMS to measure the following parameters:

NOx concentration in ppm
The CEMS shall be installed, operating, and certified no later than 12 months after the initial start-up of the turbine. During the interim period between the initial start-up and the provisional certification date of the CEMS, the operator shall comply with the monitoring requirements of Rule 2012(h)(2) and 2012(h)(3). Within 2 weeks of the turbine start-up date, the operator shall provide written notification to the District of the exact date of start-up.
[Rule 2012]

99-1 The 2.5 ppm NOx emission limit shall not apply during startups. Startup shall not exceed 20 minutes/day. The 2.5 ppm NOx limit shall apply at all other operating times.
[Rule 2005]

99-2 The 4 ppm CO emission limit shall not apply during startups. Startup shall not exceed 20 minutes/day. The 4 ppm CO limit shall apply at all other operating times.

[Rule 1303 – BACT]

99-3 The 101.15 lbs/mmscf NOx emission limit shall only apply during the interim reporting period to report RECLAIM emissions. The interim reporting period shall not exceed 12 months from the initial start-up date.
[Rule 2012]

195-1 The 2.5 ppm NOx emission limit is based on a 1 hour average, at 15 percent oxygen, dry.
[Rule 2005]

195-2 The 4 ppm CO emission limit is based on a 1 hour average, at 15 percent oxygen, dry.
[Rule 1303 – BACT]

296-1 This equipment shall not be operated unless the operator demonstrates to the Executive Officer that the facility holds sufficient RTCs to offset the prorated annual emission increase for the first compliance year of operation. In addition, this equipment shall not be operated unless the operator demonstrates to the Executive Officer that, at the commencement of each compliance year after the first compliance year of operation, the facility holds sufficient RTCs in an amount equal to the annual emission increase.
[Rule 2005]

327-1 For the purposes of determining compliance with District Rule 475, combustion contaminant emissions may exceed the concentration limit or the mass emission limit listed, but not both limits at the same time.
[Rule 475]

<u>SCR Conditions</u>

12-3 The operator shall install and maintain a continuous monitoring system to accurately indicate the ammonia injection rate of the ammonia injection system.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.
[Rule 1303 – BACT, Rule 2012]

12-4 The operator shall install and maintain a temperature gauge to accurately indicate the temperature in the exhaust at the inlet to the SCR reactor.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.
[Rule 2012]

12-5 The operator shall install and maintain a pressure gauge to accurately indicate the pressure across the SCR catalyst bed in inches water column.

The operator shall also install and maintain a device to continuously record the parameter being measured.
The measuring device or gauge shall be accurate to within plus or minus 5 percent. It shall be calibrated once every 12 months.
[Rule 2012]

179-1 For the purpose of the following condition numbers, continuous monitoring shall be defined as measuring at least once every hour, and shall be based upon the average of the continuous monitoring for that hour.

Condition number 12-3, 12-4
{Rule 1303 – BACT, Rule 2012]

179-2 For the purpose of the following condition numbers, continuous monitoring shall be defined as measuring at least once every month, and shall be based upon the average of the continuous monitoring for that month.

Condition number 12-5
{Rule 2012]

195-3 The 5 ppmv NH3 emission limit are averaged over 60 minutes at 15 percent O2 dry. The operator shall calculate and continuously record the NH3 slip concentration using the following: NH3(ppmv)=[a-b*c/1E6]*1E6/b, where a=NH3 injection rate (lb/hr)/17(lb/lbmole), b=dry exhaust gas flow rate(lb/hr)/29(lb/lbmole), and c=change in measured NOx across the SCR (ppmvd at 3 percent O2). The operator shall install and maintain a NOx analyzer to measure the SCR inlet NOx ppm, or other method as approved by the AQMD, accurate to within +/- 5 percent calibrated at least once every 12 months.
[Rule 1303-BACT]

Ammonia Storage Tank Conditions

57-1 The operator shall vent this equipment to the loading truck through the vapor return line whenever the tank is being filled.
[Rule 1303 – BACT]

71-1 The operator shall only use this equipment for the storage of aqueous ammonia, 19 percent by weight. The storage vessel shall be constructed with secondary containment with a minimum holding capacity of 5500 gallons.
[Rule 1303 – BACT]

157-1 The operator shall install and maintain a pressure relief valve set at 25 psig.
[Rule 1303-BACT]

Appendix A

Criteria Pollutant Calculations

I. Phase 1

Data:

heat rate (HHV)	11,499 btu/kWh
LHV	953 btu/scf
HHV	1050 btu/scf
Rated Turbine Output	25 MW

1. Maximum Heat Input

heat input = 11,499 X 25,000 = 287.5 mmbtu/hr

2. Maximum Exhaust Flow

(8710 dscf/mmbtu X [20.9/(20.9-15)] X 287.5 mmbtu/hr = 8,870,544 scfh

3. Maximum Fuel Use, Natural Gas

287.5 mmbtu/hr/(1050 btu/scf) = 0.2738 mmcfh

- Phase I Emissions Rates

Pollutant	No Control	Water Injection
NOx	75 ppm	20 ppm
CO	120	40
ROG	12	4
PM10	0.0066 lbs/mmbtu	0.0066 lbs/mmbtu
SOx	0.83 lbs/mmcf	0.83 lbs/mmcf

- Phase I Start Up Scenario

			Emission Rates		
	Time from Start	Control/Load	NOx	CO	VOC
Phase 1	0-5 minutes	no control, 40% load	75	120	12
	6-10 minutes	water inj, 70%	20	40	4

		load			
	11-60	water inj, 100% load	20	40	4

➢ Phase 1 Start Up Emissions

	Uncontrolled, Minutes 0-5, 40% Load		Water Injection, Minutes 6-10, 70% Load		Water Injection, Minutes 11-60,100% Load		
Pollutant	Emission Factor	Emission Rate	Emission Factor	Emission Rate	Emission Factor	Emission Rate	Total Start Up Emissions 1 Turbine
	ppm	lbs/hr	ppm	lbs/hr	ppm	lbs/hr	lbs/start
NOx	75(2)	32.30	20(2)	15.07	20(2)	21.53	21.89
CO	120(2)	31.46	40(2)	18.35	40(2)	26.21	26.00
VOC	12(2)	1.80	4(2)	1.05	4(2)	1.50	1.49
PM10	0.0066 lbs/mmbtu (1)	0.76	0.0066	1.33	0.0066	1.90	1.76
SO2	0.83 lbs/mmcf (3)	0.09	0.83	0.16	0.83	0.23	0.21

Notes:
(1) AP-42 Emission Factor
(2) Applicant's data
(3) Form B-2 factor

➢ Phase 1 Baseload Emissions

	Water Inj, 100% Load	
Pollutant	Emission Factor	Emission Rate
	ppm	lbs/hr
NOx	20	21.53
CO	40	26.21
ROG	4	1.50
PM10	0.0066 lbs/mmbtu	1.90
SO2	0.83 lbs/mmcf	0.23

➢ Phase I Hourly Emissions Summary

Pollutant	Baseload Operation, 1 Turbine	Start Up Hour, 1 Turbine
	lbs/hr	lbs/hr
NOx	21.53	21.89
CO	26.21	26.00
VOC	1.50	1.49

PM10	1.90	1.76
SOx	0.23	0.21

Examples: Start Ups

NOx, 1st 5 minutes	= (8,870,544(0.4) x 75 x 46)/379E6	=	32.30 lbs/hr
NOx, minutes 6-10	= (8,870,544(0.7) x 20 x 46)/379E6	=	15.07
NOx, minutes 11-60	= (8,870,544 x 20 x 46)/379E6	=	21.53
Total NOx =	32.30(5/60) + 15.07(5/60) + 21.53(50/60)	=	25.49 lbs
CO, 1st 5 minutes	= (8,870,544 (0.4) x 120 x 28)/379E6	=	31.49 lbs/hr
CO, minutes 6-10	= (8,870,544 (0.7) x 40 x 28)/379E6	=	18.35
CO, minutes 11-60	= (8,870,544 x 40 x 46)/379E6	=	26.21
Total CO =	31.29(5/60) + 18.25(5/60) + 26.08(50/60)	=	26.00 lbs
PM10, 1st 5 minutes	= (287.5 mmbtuh(0.4) x 0.0066)	=	0.76 lbs/hr
PM10, minutes 6-10	= (287.5 mmbtuh(0.7) x 0.0066)	=	1.33
PM10, minutes 11-60	= (287.5 mmbtuh x 0.0066)	=	1.90
Total PM10 emissions =	0.76(5/60) + 1.32(5/60) + 1.89(50/60)	=	1.76 lbs

Examples: Baseload

NOx =	(8,870,544 x 20 x 46)/379E6	=	21.53 lbs/hr
CO =	(8,870,544 x 40 x 46)/379E6	=	26.21
PM10 =	(287.5 mmbtuh x 0.0066)	=	1.90

II. Phase II

Data:

heat rate (HHV)	8,804 btu/kWh
LHV	953 btu/scf
HHV	1050 btu/scf
Rated Turbine Output	27.353 MW

1. Maximum Heat Input

heat input = 8,804 X 27,353 = 240.8 mmbtu/hr

2. Maximum Exhaust Flow

(8710 dscf/mmbtu X [20.9/(20.9-15)] X 240.8 mmbtu/hr = 7,429,660 scfh

3. Maximum Fuel Use, Natural Gas

240.8 mmbtu/hr/(1050 btu/scf) = 0.2293 mmcfh

- Phase II Emissions Rates

Pollutant	No Control	Water Injection	Water Inj/SCR/CO Cat
NOx	75	20	2.5
CO	120	40	4
ROG	12	4	1.4
PM10	0.0066	0.0066	0.0066 + SO2/SO3 conv.
SOx	0.83	0.83	0.83

- Phase II Start Up Scenario

			Emission	Rates		
	Time from Start	Control/Load	NOx	CO	VOC	NH3
Phase II	0-10 minutes	no control, 40% load	75	120	12	0
	11-20 minutes	steam inj, 70% load	25	40	4	0
	21-60 minutes	steam inj/SCR/CO cat	2.5	4	1.4	5

- Phase II Start Up Emissions

	Uncontrolled, Minutes 0-10, 40% Load		Steam Injection, Minutes 11-20, 70% Load		Steam Inj/SCR/CO Cat, Minutes 21-60,100% Load		
Pollutant	Emission Factor	Emission Rate	Emission Factor	Emission Rate	Emission Factor	Emission Rate	Total Start Up Emissions 1 Turbine
	ppm	lbs/hr	ppm	lbs/hr	ppm	lbs/hr	lbs/start
NOx	75 (2)	27.05	25 (2)	15.78	2.5 (4)	2.25	8.64
CO	120 (2)	26.35	40 (2)	15.37	4 (4)	2.20	8.42
ROG	12 (2)	1.51	4 (2)	0.88	1.4 (4)	0.44	0.69
PM10	0.0066 lbs/mmbtu (1)	0.64	0.0066	1.11	0.0076 (5)	1.83	1.51
SO2	0.83 lbs/mmcf (3)	0.08	0.83	0.13	0.332 (6)	0.076	0.086
NH3	no NH3 inj	0	no NH3 inj	0	5 (4)	1.67	1.11

Notes:
(1) AP-42 Emission Factor
(2) Applicants data
(3) Form B-2 factor
(4) Control system vendor guarantee
(5) AP-42 factor + SO2/SO3 conversion
(6) Form B-2 factor minus SO2/SO3 conversion

- Phase II Baseload Emissions

	Steam Inj/SCR/CO Cat, 100% Load	
Pollutant	Emission Factor	Emission Rate
	ppm	lbs/hr
NOx	2.5	2.25
CO	4	2.20
ROG	1.4	0.44
PM10	0.0076 lbs/mmbtu	1.83
SO2	0.332 lbs/mmcf	0.076
NH3	5	1.67

- Phase II Hourly and Daily Emissions Summary

Pollutant	Baseload Operation, 1 Turbine	Start Up Hour, 1 Turbine	1 hr start-up and 23 hrs baseload, Lbs/day, 1 Turbine
	lbs/hr	lbs/hr	Lbs/day
NOx	2.25	8.64	60.4
CO	2.20	8.42	59.0
VOC	0.44	0.69	10.8
PM10	1.83	1.51	43.6
SOx	0.076	0.086	1.83
NH3	1.67	1.11	39.52

Examples: Start Ups

NOx, 1st 10 minutes = (7,429,660(0.4) x 75 x 46)/379E6 = 27.05 lbs/hr
NOx, minutes 11-20 = (7,429,660(0.7) x 25 x 46)/379E6 = 15.78
NOx, minutes 21-60 = (7,429,660 x 2.5 x 46)/379E6 = 2.25
Total NOx = 27.05(10/60) + 15.78(10/60) + 2.25(40/60) = 8.64 lbs

CO, 1st 10 minutes = (7,429,660(0.4) x 120 x 28)/379E6 = 26.35 lbs/hr
CO, minutes 11-20 = (7,429,660(0.7) x 40 x 28)/379E6 = 15.37
CO, minutes 21-60 = (7,429,66 x 4 x 28)/379E6 = 2.20
Total CO = 26.35(10/60) + 15.37(10/60) + 2.20(40/60) = 8.42 lbs

PM10, 1st 10 minutes = (240.8 mmbtuh(0.4) x 0.0066) = 0.64 lbs/hr
PM10, minutes 10-20 = (240.8 mmbtuh(0.7) x 0.0066) = 1.11
PM10, minutes 21-60 = (240.8 mmbtuh x 0.0076) = 1.83
Total PM10 = 0.76(10/60) + 1.32(10/60) + 1.89(40/60) = 1.51 lbs

Examples: Baseload

NOx = (7,429,660 x 2.5 x 46)/379E6 = 2.25 lbs/hr
CO = (7,429,660 x 4 x 28)/379E6 = 2.20
PM10 = (240.8 mmbtuh x 0.0076) = 1.83

C. Maximum Daily Emissions

Pollutant	Operating Scenario	Emissions
		lbs/day
NOx	Phase I, start-up + maximum baseload	517.08
CO	Phase I, maximum baseload (no start)	629.04
VOC	Phase I, maximum baseload (no start)	36.00
PM10	Phase I, maximum baseload (no start)	45.60
SOx	Phase I, max baseload (no start)	5.52
NH3	Phase II, maximum base load (no start)	47.52

Examples:

NOx	=	21.89 lbs/hr+ 23(21.53 lbs/hr)	=	517.08 lbs/day
CO	=	26.21 lbs/hr x 24	=	629.04
VOC	=	1.50 lbs/hr x 24	=	36.00
PM10	=	1.90 lbs/hr x 24	=	45.60
SOx	=	0.23 lbs/hr x 24	=	5.52
NH3	=	1.98 lbs/hr x 24	=	47.52

D. 30 Day Average Emissions

The estimate of 30 day average emissions are based on the following assumptions:

One month consists of 30 days, 720 hours
The turbines will undergo 1 start up event per day, lasting 1 hour each, for a total of 30 hours per month per turbine.
For the remaining hours the turbines will operate under maximum load.

Pollutant	Start ups (30 hours)	Normal Operation (690 hours)	Total Emissions	30 Day Average Emissions, 1 Turbine
	lbs	lbs	lbs/month	lbs/day
NOx	656.70	14855.70	15512.4	517.08
CO	780.00	18,084.90	18864.90	628.83*
VOC	44.70	1028.1	1072.8	35.76*
PM10	52.80	1311.00	1363.80	45.46*
SOx	6.30	158.70	165.00	5.5*

* For CO, VOC, PM10, and SOx, due to lower heat inputs, when start ups are included in the emission estimates, the results are lower than if 24 hr/day, 30 day/month baseload

operation is assumed (baseload operation: CO – 26.21 lbs/hr, 629.04 lbs/day, and 18871.2 lbs/month, PM10 – 1.90 lbs/hr, 45.60 lbs/day, and 1368 lbs/month, VOC - 1.50 lbs/hr, 36.0 lbs/day, and 1080.0 lbs/month, SOx – 0.23 lbs/hr, 5.52 lbs/day, and 165.6 lbs/month). Therefore, the baseload emissions will be used for 30 day average offset purposes.

E. NH3 Emissions

based on 5 ppm guaranteed ammonia slip:

5 ppm X 7.430 mmscfh X 17 lbs/lb-mole/(379 scf/lb-mole) = 1.67 lbs/hr

Appendix B

Emission Factors

Phase I Emission Factors, Fuel Use Basis

Pollutant	Start Up	Baseload
	lbs/mmcf	lbs/mmcf
NOx	101.15(1)	78.63(2)
CO	102.62(3)	95.74(4)
ROG	5.87(5)	5.47(6)
PM10	6.94(7)	6.94(7)
SOx	0.83(8)	0.83(8)

Notes:

(1) Based on 25.49 lbs/hr, and 0.2724[(0.4)5/60 + (0.7)5/60 + (1.0)50/60] = 0.2520 mmcfh fuel use
(2) Based on 20 ppm, 8.824 mmcfh exhaust rate, 0.2724 mmcfh fuel use
(3) Based on 25.86 lbs/hr, and 0.2520 mmcfh fuel use
(4) Based on 40 ppm, 8.824 mmscfh exhaust rate, 0.2724 mmscf fuel use.
(5) Based on 1.48 lbs/hr, and 0.2520 mmcfh fuel use
(6) Based on 4 ppm, 8.824 mmcfh exhaust rate, 0.2724 mmcfh fuel use
(7) Based on *AP-42 Emission Factor Development Document, Table 3.4-1 (all loads) factor* of 0.0066 lbs/mmbtu.
(8) Based on Form B-2 Factor

Phase I Emission Factors, Heat Input Basis

Pollutant	Start Up	Baseload
	lbs/mmbtu	lbs/mmbtu
NOx	0.096(1)	0.0749(2)
CO	0.098(3)	0.0912(4)
ROG	0.00559(5)	0.00521(6)
PM10	0.0066(7)	0.0066(7)
SOx	0.000794(8)	0.000804(9)

(1) Based on 25.49 lbs/hr, and 286[(0.4)5/60 + (0.7)5/60 + (1.0)50/60] = 264.6 mmbtuh heat input
(2) Based on 20 ppm, 8.824 mmcfh exhaust rate, 286 mmbtuh heat input
(3) Based on 25.86 lbs/hr, and 264.6 mmbtuh heat input

(4) Based on 40 ppm, 8.824 mmscfh exhaust rate, 286 mmbtuh heat input.
(5) Based on 1.48 lbs/hr, and 264.6 mmbtuh heat input.
(6) Based on 4 ppm, 8.824 mmcfh exhaust rate, 286 mmbtuh heat input.
(7) Based on *AP-42 Emission Factor Development Document, Table 3.4-1 (all loads)*
(8) Based on Form B-2 Factor, 0.2520 mmscf fuel use and 264.6 mmbtu/hr heat input.
(9) Based on Form B-2 Factor, 0.2724 mmscf fuel use and 286 mmbtu/hr heat input.

Phase I Controlled NOx Emissions, LB/MWh:

Hourly Emission Rate	Net MW Output	Emissions per MW
lbs/hr	MW	lbs/MWh
21.42	25	0.857

Based on an outlet NOx concentration of 20 ppm, and an exhaust flow of 8.824 mmcfh.

Phase II Emission Factors, Fuel Use Basis

Pollutant	Start Up	Baseload
	lbs/mmcf	lbs/mmcf
NOx	44.33 (1)	9.81 (2)
CO	43.20 (3)	9.59 (4)
ROG	18.16 (5)	1.92 (6)
PM10	7.75 (7)	7.98 (7)
SOx	0.39 (8)	0.38 (8)

Notes:
(1) Based on 8.64 lbs/hr, and 0.2293[(0.4)10/60 + (0.7)10/60 + (1.0)40/60] = 0.1949 mmcfh fuel use.
(2) Based on 2.5 ppm, 7.430 mmcfh exhaust rate, 0.2293 mmcfh fuel use
(3) Based on 10.00 lbs/hr, and 0.1949 mmcfh fuel use
(4) Based on 4 ppm, 7.430 mmscfh exhaust rate, 0.2293 mmscf fuel use.
(5) Based on 0.82 lbs/hr, and 0.1949 mmcfh fuel use
(6) Based on 1.4 ppm, 7.430 mmcfh exhaust rate, 0.2293 mmcfh fuel use
(7) Based on *AP-42 Emission Factor Development Document, Table 3.4-1 (all loads) factor* of 0.0066 lbs/mmbtu.
(8) Based on Form B-2 Factor, adjusted for SO2/SO3 conversion

Phase II Emission Factors, Heat Input Basis

Pollutant	Start Up	Baseload
	lbs/mmbtu	lbs/mmbtu
NOx	0.0728(1)	0.00937(2)
CO	0.0411(3)	0.0913(4)
ROG	0.00337(5)	0.00182(6)
PM10	0.0066(7)	0.0066(7)
SOx	0.000782(8)	0.000804(9)

(1) Based on 17.69 lbs/hr, and 286[(0.4)10/60 + (0.7)10/60 + (1.0)40/60] = 243.1 mmbtuh heat input.
(2) Based on 20 ppm, 8.824 mmcfh exhaust rate, 286 mmbtuh heat input
(3) Based on 10.00 lbs/hr, and 243.1 mmbtuh heat input
(4) Based on 4 ppm, 8.824 mmscfh exhaust rate, 286 mmbtuh heat input.
(5) Based on 0.82 lbs/hr, and 243.1 mmbtuh heat input.
(6) Based on 1.4 ppm, 8.824 mmcfh exhaust rate, 286 mmbtuh heat input.
(7) Based on *AP-42 Emission Factor Development Document, Table 3.4-1 (all loads)*
(8) Based on Form B-2 Factor, 0.2315 mmscf fuel use and 243.1 mmbtu/hr heat input.
(9) Based on Form B-2 Factor, 0.2724 mmscf fuel use and 286 mmbtu/hr heat input.

Phase II Controlled NOx Emissions, LB/MWh:

Hourly Emission Rate	Net MW Output	Emissions per MW
lbs/hr	MW	lbs/MWh
2.68	25	0.107

Based on an outlet NOx concentration of 2.5 ppm, and an exhaust flow of 8.824 mmcfh.

Appendix C

NSPS Calculations

Since turbine rating is greater than 100 mmbtu/hr, use:

STD = $0.0075\frac{14.4}{Y} + F$

60.332 (a)(1)

Where:

STD = allowable NOx emissions in percent volume at 15%, dry
Y = manufacturer's rating in KJ/watt-hr
F = 0 for fuel with nitrogen content < 0.015%w

Y = 11.439 btu/Wh X (1055 joules/btu) X (KJ/1000 J)
Y = 12.068 KJ/Watt-hr

1. Natural Gas

For natural gas, nitrogen <0.015%w, therefore:

STD = 0.0075(14.4/12.068) + 0 = 0.008949
= 89.5 ppm

Appendix D

Summary of Fuel Analyses

Stocker Resources samples their sales gas on a weekly basis. They provided 1 of these analyses for each of the last 12 months. Following is a summary of the analyses:

Sample Date	H2S Content	Dry BTU Content
	ppm	btu/ft3
7/25/00	2.5	1076
8/2/00	2	1072
9/29/00	0.75	1076
10/6/00	1	1073
11/3/00	1.5	1072
12/9/00	2.5	1097
1/13/01	5	1097
2/13/01	0.5	1090
3/27/01	0	1061
4/14/01	0	1073
5/22/01	0	1074
6/6/01	0.5	1097
Average	1.35	1080

Appendix E

Toxic and Carcinogenic Emission Factors

The following emissions were calculated using emission factors from AP-42. These emission rates were used in the HRA modeling analysis (see Appendix F).

	EF	Emissions (lbs)		Emission rate (g/s)	
Toxic	(lb/MMBtu)	Max. Hourly	Annual	Max. Hourly	Annual
Acetaldehyde	4.0E-05	0.0100	81.82	1.26E-03	1.18E-03
Acrolein	6.4E-06	0.0016	13.09	2.01E-04	1.88E-04
Benzene	1.2E-05	0.0030	24.55	3.77E-04	3.53E-04
Ethylbenzene	3.2E-05	0.0080	65.46	1.01E-03	9.42E-04
Formaldehyde	7.1E-04	0.1770	1452.38	2.23E-02	2.09E-02
Napthalene	1.3E-06	0.0003	2.66	4.08E-05	3.82E-05
PAH (w/o napthalene)	9.0E-07	0.0002	1.84	2.83E-05	2.65E-05
Toluene	1.3E-04	0.0324	265.93	4.08E-03	3.82E-03
Xylenes	6.4E-05	0.0160	130.92	2.01E-03	1.88E-03

Appendix F

Modeling Summary

The applicant performed modeling to show compliance with Rule 1303 and Rule 2005 limits.

The following emissions were used in the model:

	Interim Project			Permanent Project		
Pollutant	Max Hourly	Max Daily	Annual	Max Hourly	Max Daily	Annual
	lbs/hr	lbs/day	lbs/yr	lbs/hr	lbs/day	lbs/yr
NOx	21.89	517	188705	8.64	60	1440
CO	26.21	629	229585	8.42	59	1416
PM10	1.90	46	16790	1.59	38	912

The following stack parameter were used in the model:

Parameter	Value
Stack Height	21.3 meters
Stack Temperature	783°F
Exit Velocity	26.57 m/s
Stack Diameter	2.7 m

The modeling was reviewed by AQMD modeling staff for methodology and accuracy of results. According to the 6/8/01 memo from Henry Hogo to Pang Mueller, the modeling was done correctly and the results meet the requirements of Rules 1303, 2005, and 1401. Following is the memo:

SOUTH COAST AIR QUALITY MANAGEMENT DISTRICT

M E M O R A N D U M

DATE: June 8, 2001

TO: Pang Mueller

FROM: Henry Hogo

SUBJECT: Review of the Revised Air Quality Impact Analysis for the La Jolla Energy Development Inc. Turbine Project

Per your request, we have reviewed the revised air quality impact analysis for the La Jolla Energy Development Inc. turbine project. The original air quality impact analysis was inadequate for the reasons outlined in our memo of May 29, 2001.

La Jolla Energy Development Inc. is proposing to install two new General Electric LM 2500 simple cycle turbine engines at the Baldwin Energy Facility No. 1 located at 5640 South Fairfax Avenue, Los Angeles, California. Each turbine will have approximately 25 MW output of electricity. The focus of our review is the proposed permanent project, which includes the installation of the following controls: steam injection utilizing heat recovery steam generators, selective catalytic reduction (SCR), and an oxidation catalyst. District Rules 1303 and 1401 are relevant to this project. Our summarized comments are given as follows and more detailed comments are presented in Attachment 1.

Rule 1303 – The air quality impacts from the project will be in compliance with Rule 1303. In addition, the interim project (without SCR) will not cause a violation or make measurably worse an existing violation of any California or national ambient air quality standard.

Rule 1401 – The health impacts from the project will be in compliance with Rule 1401.

Potential Nuisance from Ammonia Slip – The peak one-hour ammonia concentration as a result of slip are well below the ammonia odor threshold.

Please direct any questions to Tom Chico at extension 3149.

TC:(c:\My Documents\la_jolla.doc)

Cc: Mike Nazemi
Chris Perri

Attachment 1

Detailed Comments on the Air Quality Impact Analysis

Rule 1303

- The air quality impacts are presented as the total impact from the two proposed combustion turbine generators. The applicant used the U.S. Environmental Protection Agency's ISCST model (version 00101) with appropriate model options. All source parameters and emission rates are assumed to be correct. The applicant used the West Los Angeles meteorological data for their modeling, which is appropriate for the project impact area. The applicant used 100 meter grid spacing along the property boundary and within the maximum impact areas. The applicant incorrectly determined the background concentrations for CO, SO_2, PM_{10} and NO_2. Instead of using the most recent year to establish background air quality, the maximum concentrations over the most recent three-year period should be used. This minor error was corrected and the project impacts are summarized in Table 1.
- Currently, the project impact area meets the most stringent ambient air quality standards for CO, NO_2, and SO_2 (see Table 1; column #4). The project impact area will continue to meet these standards even with the addition of the project's incremental impacts (see Table 1; column #5). Although the project impact area does not meet the most stringent PM_{10} ambient air quality standards, the project increments are less than the PM_{10} significance thresholds in Rule 1303.
- The visibility requirements of Rule 1303 are not triggered since the PM_{10} and NO_X emissions are below the thresholds of 15 tons/yr and 40 tons/yr, respectively (see Rule 1303(b)(5)(C)). Also, the proposed facility is located beyond the range of all the nearby federal Class I areas (see Table 11 of the applicant's June 5, 2001 submittal).
- **Summary** – The applicant performed their air quality analysis per the District's modeling requirements except as discussed above. The air quality and visibility impacts from the proposed project will be in compliance with Rule 1303.

Comments on the Rule 1401 Analysis

- A health risk assessment (HRA) was prepared for the proposed project (i.e., the two combustion turbines) by the applicant. However, the District staff did not agree with the toxic emissions used in the HRA.
- District staff estimated toxic risks from the facility using the dispersion model ISCST (version 00101) and the risk assessment model, ACE2588. Emission factors from U.S. EPA AP-42 were used.
- The project's toxic pollutant impacts are summarized in Table 3, where the impacts are compared to the significance thresholds of Rule 1401. Cancer risks at the nearest commercial and residential receptors are below 1 in one million, which is below the significance thresholds of Rule 1401. The acute and chronic non-cancer hazard indices are also below the Rule 1401 thresholds.
- **Summary** – There were problems with the toxic emissions used in the impact assessment so District staff prepared an HRA. The results from the HRA indicate that the project will be in compliance with Rule 1401.

Ammonia Odors

- The applicant estimated the emissions as a result of ammonia slip, which were input to ACE2588 risk assessment model. The peak one-hour ammonia concentration is estimated to be 4.6 $\mu g/m^3$. An odor threshold of 20 ppm (13,900 μg/m^3) has been cited in the literature. Therefore, odor complaints from ammonia slip are not expected.

Table 1. Summary of Modeling Results for the Interim Project Relative to Rule 1303.

Pollutant	Averaging Period	Increment (μg/m^3)	Background (μg/m^3)*	Total Conc. (μg/m^3)	Exceed CAAQS?**
CO	1-hour	28.1	8050	8078	No
	8-hour	19.0	5175	5194	No
NO_2	1-hour	27.9	300.8	328.7	No
	Annual	1.2	54.7	55.9	No
SO_2	1-hour	0.4	445.4	445.8	No
	24-hour	0.2	52.4	52.6	No
	Annual	0.04	10.5	10.5	No
PM_{10}	24-hour	0.7	74	74.7	Yes***
	Annual geometric mean	0.2	33.4	33.6	Yes***

* Peak background conditions at West Los Angeles (#091) and Hawthorne (#094) over the period 1998-2000 were used.

** California Ambient Air Quality Standards (CAAQS):
CO (1-hr) = 23,000 μg/m^3
CO (8-hr) = 10,000 μg/m^3
NO_2 (1-hr) = 500 μg/m^3
NO_2 (annual) = 100 μg/m^3
SO_2 (1-hr) = 650 μg/m^3
SO_2 (24-hr) = 110 μg/m^3
SO_2 (annual) = 80 μg/m^3
PM_{10} (24-hr) = 50 μg/m^3
PM_{10} (AGM) = 30 μg/m^3

*** Project increments are within the PM_{10} significance thresholds of 2.5 μg/m^3 (24-hr) and 1 μg/m^3 (annual).

Table 2. Summary of Modeling Results for the Permanent Project Relative to Rule 1303.

Pollutant	Averaging Period	Increment (μg/m^3)	Background (μg/m^3)*	Total Conc. (μg/m^3)	Exceed CAAQS?**
CO	1-hour	23.3	8050	8073	No
	8-hour	8.2	5175	5183	No
NO_2	1-hour	23.9	300.8	324.7	No
	Annual	0.3	54.7	55.0	No
SO_2	1-hour	0.4	445.4	445.8	No
	24-hour	0.2	52.4	52.6	No
	Annual	0.04	10.5	10.5	No
PM_{10}	24-hour	1.8	74	75.8	Yes***
	Annual geometric mean	0.4	33.4	33.8	Yes***

* Peak background conditions at West Los Angeles (#091) and Hawthorne (#094) over the period 1998-2000 were used.

** <u>California Ambient Air Quality Standards (CAAQS):</u>
CO (1-hr) = 23,000 μg/m^3
CO (8-hr) = 10,000 μg/m^3
NO_2 (1-hr) = 500 μg/m^3
NO_2 (annual) = 100 μg/m^3
SO_2 (1-hr) = 650 μg/m^3
SO_2 (24-hr) = 110 μg/m^3
SO_2 (annual) = 80 μg/m^3
PM_{10} (24-hr) = 50 μg/m^3
PM_{10} (AGM) = 30 μg/m^3

*** Project increments are within the PM_{10} significance thresholds of 2.5 μg/m^3 (24-hr) and 1 μg/m^3 (annual).

Table 3. Summary of Modeling Results Relative to Rule 1401.

Criteria	Exposure Type	Impacts	**Exceeds R1401 Signif. Thresholds?**
Cancer risk	MEIW	0.16 in one million	No
	MEIR	0.91 in one million	No
Acute Hazard Index	Maximum	0.0299	No
Chronic Hazard Index	Maximum	0.0152	No

<u>Exposure Type:</u>
MEIW = maximum exposed individual worker
MEIR = maximum exposed individual resident
Maximum = absolute maximum off-site impact

<u>Rule 1401 Significance Thresholds:</u>
Cancer risks = 1 in one million without T-BACT & 10 in one million with T-BACT
Acute hazard index = 1
Chronic hazard index = 1

Appendix G

Annual Criteria Pollutant Emission Estimates

Pollutant	Existing Facility 1999-2000 Reported Annual Emissions(1)	New Turbines(2)	Combined Facility
	tons	tons	tons
NOx	48	104.73	152.73
CO	28	124.71	152.71
VOC	14	8.49	22.49
PM10	2	15.26	17.26
SOx	0.04	1.83	1.87
NH3	0	7.36	7.36

Notes:

(1) For Stocker Resources ID# 87533. Since the 1999-2000 emissions report, NOx emissions have been reduced by the electrification of 8 IC engines previously on site. Current NOx levels are less than 10 tpy.

(2) Includes 181 days at the interim project and 184 days at the permanent project emission levels.

Appendix H

SO2/SO3 Conversion

With the addition of the SCR and ammonia injection in Phase II of the project, along with an oxidation catalyst, and reduced exhaust gas temperatures (below 400°F), there will be a conversion of SO2/SO3 with resultant formation of ammonium sulfate in the exhaust. This conversion results in an increase in PM10 emissions, and a reduction in SOx emissions.

Following is the calculation:

La Jolla Energy Project
SO2/SO3 Conversion

DATA

PM10 Emission Rate	1.59	lbs/hr
SOX Emission Rate	0.19	
Conversion with CO Catalyst	60%	
SO2 mole wt	64	lbs/lb-mole
SO3 mole wt	80	
(NH4)2SO4 mole wt	132	

CALCULATIONS

Converted SO2	0.114	lbs/hr
SO3 wt	0.143	
(NH4)2SO4 wt	0.235	
Final PM10	1.825	
Final SO2	0.076	